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Status of Flue Gas Desulfurization on Utility and Industrial Boilers in the United States and Japan

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16. ABSTRACT The report quantifies the U.S. sulfur oxide (SOx) emissions problem, and attributes it, proportionately, to its various significant sources. It briefly presents the regulatory framework applicable to the control of SO2 air pollution, and mentions projected regulatory changes. It cites various SOx control technologies, but emphasizes flue gas desulfurization (FGD). It briefly describes processes for currently operating full-scale FGD systems. It discusses the current status of FGD systems applied to utility and industrial boilers, with emphasis on utility systems. It gives the number of units and controlled capacity for systems currently operating, under construction, and planned. It discusses major problems incident to the application of FGD systems, with respect to their impact on system dependability. It tabulates capital and annual costs of FGD systems for actual operating systems, and presents adjusted costs for these systems to permit system/type comparisons. It also gives cost estimates for generalized or model plant designs, and compares these estimates with reported and adjusted actual system costs. (Projected growth of FGD use is based on curtently planned utility units and more stringent regulations.) The report compares these projected growth rates of utility FGD applications with a projected need for FGD. The status of FGD systems in Japan is also described.

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Flue Gases	Stationary Sources	21B
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STATUS OF FLUE GAS DESULFURIZATION ON UTILITY AND INDUSTRIAL BOILERS IN THE UNITED STATES AND JAPAN

EPA-600/J-80-109
JOURNAL ARTICLE

by Norman Kaplan
and
Michael A. Maxwell

The sulfur oxide (SO_x) emissions problem is quantified and attributed, proportionally, to the various significant sources in the United States.

The regulatory framework applicable to control of sulfur dioxide (SO_2) air pollution is briefly presented. Projected regulatory changes are mentioned.

Various SO_x control technologies are cited; however, flue gas desulfurization (FGD) is emphasized. Processes are briefly described for the currently operating full-scale FGD systems.

The current status of FGD systems applied to utility and industrial boilers is discussed with emphasis on the utility systems. The number of units and controlled capacity are given for systems currently operating, under construction, and planned. Major problems incident to the application of FGD systems are discussed with respect to their impact on system dependability.

Capital and annual costs of FGD systems are tabulated for actual operating systems, and adjusted costs are presented for these systems to permit system-type comparisons. Cost estimates are also provided for generalized or model plant designs, and these estimates are compared with the reported and adjusted actual system costs.

Projected growth of FGD use is based on currently planned utility units and more stringent regulations. These projected growth rates of utility FGD applications are then compared with a projected need for FGD.

The Federal energy/environment research and development programs are briefly described, with emphasis on the large-scale demonstration test programs.

The status of FGD systems in Japan is briefly summarized. The Japanese regulatory climate and other possible reasons for the improved operation of Japanese over U.S. FGD systems are discussed.

INTRODUCTION

The SO_2 Emissions Problem

Recent estimates by the U.S. Environmental Protection Agency (EPA) place sulfur oxide (SO_x) emissions at about 26 to 30 million metric tons per year. Most of the SO_x emissions come from a relatively small variety of sources. About 80% of all emissions are from stationary source fuel combustion and about two-thirds of all emissions are from the electric utility industry. The remaining 20% can be primarily attributed to a few industrial processes: metals smelting and refining, petroleum refining, mineral products processing, and chemicals manufacturing. Approximately 60% of the industrial emissions are attributable to the metals industries, with the remainder being divided somewhat evenly among the other three areas.

Nationally, SO_x emissions are being stabilized and even showing a slight downtrend, from a total of 29.1 million tons in 1970 to approximately 26.9 million tons in 1976. The downtrend is largely due to lower emissions from the industrial process sources. These sources show a reduction of one-third between 1972 and 1976, mainly in the metals smelting and refining area. It is obvious that adequate control of SO_x in our atmosphere will depend on control of SO_x emissions in combustion exhaust gases. The Nation's commitment to use our coal reserves for energy production emphasizes this fact even further.

Regulation

Sulfur dioxide is federally controlled under the Clean Air Act (amended August 1977) in two basic ways: by emission limitations and by promulgated ambient air quality standards. The states and municipalities may enact (and some have) regulations that are more stringent than Federal laws and regulations.

Emissions limitations. Federal limitations on emissions of sulfur dioxide are imposed on "new" fossil-fuel-fired steam generators by regulations promulgated on December 23, 1971. These regulations apply to steam generators with a heat input of more than 73 MW (250 million B.t.u./hr.) and for which construction or modification was initiated after August 17, 1971 (the date of proposal of the standards). The regulations limit emissions to 520 ng/J (1.2 lb./million B.t.u.) heat input for solid fuels (e.g.,

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coal) and 340 ng/J (0.8 lb./million B.t.u.) heat input for liquid fuels (e.g., oil). For example, this limitation requires removal of more than 70% of the sulfur dioxide emitted when burning a coal containing 3% sulfur and having a heating value of 28,000 J/g (12,000 B.t.u./lb.). These limitations apply to almost all utility boilers and some large industrial boilers.

The EPA is currently considering revision of these new source performance standards (NSPS) to reflect more stringent control for the larger boilers (over 73 MW input). Regulation of emissions from the smaller boilers is also being considered. At the time this paper was written, the proposed SO_2 NSPS had not yet been announced; however, indications are that any new coal-fired units not under construction by December 31, 1978 (requiring a construction permit by March 1, 1978) will be subject to the revised standards. These standards may include the following elements and possible alternatives: a continuous SO_2 removal requirement (85 or 90%)* with a lower weight emission limitation of 90 or 220 ng/J (0.2 or 0.5 lb./10^6 B.t.u.) heat input to the boiler and an upper limit of 520 ng/J (1.2 lb./10^6 B.t.u.) heat input; an emission averaging time (24 hours or 30 days); and conditions for FGD bypass (no excess emissions unless a blackout is imminent; excess emissions allowed during FGD mechanical failures; or 3 grace days during each averaging month in which SO_2 emissions can exceed a 75% control value).

In the early 1970's, the NSPS requirements were thought to be stringent and were considered the limiting legal maximum requirement. With the advances in FGD technology and several legal precedents on enforcement, the existing NSPS are now considered a limiting minimum legal requirement in the law. Environmental control requirements (such as those embodied in "Prevention of Significant Deterioration," "Best Available Control Technology," and "Lowest Achievable Emissions Rate") have in effect made the current NSPS levels the upper acceptable emission limits.

Ambient air quality standards. As mandated by the Clean Air Act, EPA's Administrator has promulgated primary and secondary national ambient air quality standards (NAAQS) for SO_2. Primary standards are designed to protect the public health, while secondary standards are meant to protect the public welfare. These standards are given in Table 1.

Although the NSPS directly limit emissions from certain new sources, the NAAQS indirectly control emissions from all sources.

To meet the primary standards, the Clean Air Act amendments require each state to adopt (and submit to the Administrator) a State Implementation Plan (SIP) to provide for implementation, maintenance, and enforcement of the primary standard as soon as practicable but not later than 3 years after the SIP is approved. The SIP requirements for implementing, maintaining, and enforcing the secondary standard must specify "a reasonable time at which such secondary standard will be attained." Attainment of these primary and secondary standards necessitates the establishment of emission standards by the states. The stringency of the state emission standards, which are applicable to existing as well as new sources, varies with the degree of control required to attain the NAAQS.

SO_x Control Technology for Combustion Processes

To control SO_x emissions from combustion sources, one can: (1) use fuels containing less sulfur, (2) remove sulfur from the fuel before combustion (coal cleaning and fuel processing), (3) remove sulfur during combustion (fluid-bed combustion), (4) remove sulfur from the flue gases after combustion (FGD), or (5) any combination of the above. The various SO_x control methods, including estimates of costs and degree of likely application, have been discussed to varying degrees in other papers. Several reports are also available that summarize the use and implications of these control measures. This paper will focus on the use of flue gas desulfurization.

OVERVIEW OF FGD PROCESSES

Flue gas desulfurization is the removal of sulfur oxides from combustion exhaust gases, in most cases by chemical reaction with an absorbent in water slurry or solution. The process takes place in an absorption tower

* With credit for precombustion processes that remove sulfur.

or other device where gas/liquid contact occurs. Certain other FGD processes under development remove sulfur oxides by dry adsorption.

Well over 50 FGD processes have been invented; many have undergone testing in small-scale laboratory or pilot-plant operations. Relatively few have served to control SO_2 emissions in full-scale utility or industrial boiler applications in this country; however, considering our commitment to coal and the potentially more stringent pollution control regulations, increased use of FGD may well be the only near-term course of action that is available.

FGD Processes In Current Use

There are currently seven types of FGD processes applied to full-scale utility systems. These are summarized in Table 2 by process type, number of systems operating, controlled generating capacity, and percentage of the total capacity controlled by each type.

The mix of FGD systems currently applied at nonutility stationary source combustion systems is summarized in Table 3.

The various FGD processes may be categorized as either regenerable or nonregenerable (perhaps more properly into salable product or throwaway processes). The regenerable or salable product processes produce sulfur or a byproduct containing sulfur that may be sold to offset partially the cost of FGD system operation. Potential products are elemental sulfur, sulfuric acid, liquid SO_2, and gypsum. (If, however, impure gypsum is produced and is disposed of as solid waste, the system would be classified as throwaway.) Throwaway or nonregenerable systems produce a liquid, solid, or sludge waste product containing the sulfur removed from the flue gases. Of the systems appearing in Tables 2 and 3, only the magnesium oxide and Wellman-Lord/Allied Chemical are salable product processes.

Based on current controlled capacity, 96% of the operating utility processes and 100% of the nonutility processes are throwaway systems. The throwaway processes are heavily favored in current application because of more favorable economics, relative simplicity of design and operation, and more extensive prior operating experience.

Process Descriptions

Brief descriptions of the most significant types of U.S. operating systems are given below. Several excellent papers and reports provide further descriptions.

Lime/limestone slurry scrubbing. In concept, lime or limestone slurry scrubbing processes are very simple. In practice, however, the chemistry and system design for a full-scale operation can be exceedingly complex.

These systems use a slurry of lime or limestone in water to absorb SO_2 from power plant flue gas in a gas/liquid scrubber. Various types of scrubbers or gas/liquid contact devices are used commercially: spray towers, grid towers, tray towers, venturis, marble-bed scrubbers (packed beds of glass spheres) and turbulent-contact absorbers (lightweight plastic spheres--ping-pong balls--held between restraining grids in a countercurrent scrubbing tower).

In a limestone slurry system, the overall absorption reaction (taking place in the scrubber and the hold tanks) produces hydrated calcium sulfite:

$$CaCO_3 + SO_2 + \tfrac{1}{2} H_2O \rightarrow CaSO_3 \cdot \tfrac{1}{2} H_2O + CO_2 \quad (1)$$

In a lime slurry system, the overall reaction is similar but yields no CO_2:

$$CaO + SO_2 + \tfrac{1}{2} H_2O \rightarrow CaSO_3 \cdot \tfrac{1}{2} H_2O \quad (2)$$

The actual reactant in Eq. 2 is $Ca(OH)_2$, because CaO is slaked in the slurrying process.

Lime and limestone slurry scrubbing systems can be engineered for almost any desired level of SO_2 removal. Commercial utility systems are generally designed for 80 to 90% removal; however, some systems have at times achieved more than 99% removal. The higher removal rate is not incrementally very costly: investment savings realized in designing for 80% rather than 90% SO_2 removal amount to only between 3.2 and 4.5% (3).

Alkaline fly ash scrubbing. Low-sulfur coals from the Western United States may be particularly suitable to SO_2 control by scrubbing the waste gases with a slurry of the alkaline fly ash. The alkaline fly ash, which is generated in the combustion process, may be added to the system in two

ways: (1) collecting the fly ash in an electrostatic precipitator upstream of the scrubber and then slurrying the dry fly ash with water so that it can be pumped into the scrubber circuit, or (2) scrubbing the fly ash directly from the flue gas by the circulating slurry of fly ash and water.

Generally, western lignites and subbituminous coals are best suited to this method. Certain of these coals (e.g., those from North Dakota, Montana, and Wyoming) contain up to 20% ash; the ash contains up to 40% alkaline constituents, including oxides of calcium, magnesium, sodium, and potassium, some of which are offset by acidic constituents (4). With potentially more stringent NSPS, this process may, however, have to be used with supplemental lime or limestone to meet standards.

Soda ash scrubbing. This method of controlling SO_2 involves scrubbing the flue gas with a solution of sodium carbonate and bicarbonate to produce a mixture of sodium sulfite and sulfate by these reactions:

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2 \qquad (3)$$

$$2\ NaHCO_3 + SO_2 + H_2O \rightarrow Na_2SO_3 + 2\ H_2O + 2\ CO_2 \qquad (4)$$

$$Na_2SO_3 + \tfrac{1}{2}\ O_2 \rightarrow Na_2SO_4 \qquad (5)$$

The sodium carbonate does not have to be pure. Nevada Power Company uses trona salt, a naturally occurring mineral containing 60% $NaHCO_3$, 20% NaCl, 10% sulfates, and 10% insolubles.

This process has definite limitations in large-scale utility applications because it requires a relatively cheap source of sodium carbonate or bicarbonate and an ability to dispose of large volumes of waste salt solution. Nevada Power is located near trona deposits, and in an area where natural evaporation rates far exceed rainfall and where land is relatively abundant. The company processes its liquid waste in solar evaporation ponds.

Magnesium oxide scrubbing. The magnesium oxide process is a regenerable or salable product process. It does not produce waste material: the SO_2 removed from the flue gas is concentrated and used to make marketable sulfuric acid or elemental sulfur.

Using a slurry of MgO or $Mg(OH)_2$ to absorb SO_2 from flue gas in a scrubber, this process yields magnesium sulfite and sulfate. When dried and calcined, the mixed sulfite/sulfate produces a concentrated stream (10 to 15%) of SO_2 and regenerates MgO for recycle to the scrubber. Carbon added to the calcining step reduces any $MgSO_4$ to MgO and SO_2.

In commercial applications, the scrubbing and drying steps would normally take place at the power plant. The regeneration and sulfuric acid production steps might be performed at a conventional sulfuric acid plant. Alternatively, a central processing plant could produce sulfur from mixed magnesium sulfite/sulfate brought in from several desulfurization locations.

Wellman-Lord system. The Wellman-Lord process is also a regenerable or salable product system. When coupled with other processing steps, it can make salable liquid SO_2, sulfuric acid, or elemental sulfur.

The Wellman-Lord process uses a solution of sodium sulfite to absorb SO_2 from waste gases in a scrubber or absorber, converting the sulfite to bisulfite:

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2\ NaHSO_3 \qquad (6)$$

Thermal decomposition of the bisulfite in an evaporative crystallizer regenerates sodium sulfite for reuse as the absorbent:

$$2\ NaHSO_3 \rightleftharpoons Na_2SO_3 + SO_2 + H_2O \qquad (7)$$

The evaporative crystallizer produces a mixture of steam and SO_2 and a slurry containing sodium sulfite/sulfate plus some undecomposed $NaHSO_3$ in solution. As water condenses from the steam/SO_2 mixture, it leaves a wet SO_2-enriched gas stream to undergo further processing for recovery of salable sulfur values.

Soluble alkali scrubbing. Most FGD processes applied to industrial boilers are of the soluble alkali type (basically similar to soda ash scrubbing, and using sodium carbonate, bicarbonate, hydroxide, or ammonia-based alkali), which converts sulfur in the flue gas to sulfite/bisulfite and sulfate in solution.

Disposal of spent scrubbing liquors includes use in pulp/paper manufacturing, discharge

to evaporation ponds, treatment (mainly by air oxidation) and discharge to city sewer systems, and treatment and discharge to rivers.

Some sodium-alkali users are considering regeneration of scrubber liquor by treating the spent liquor with calcium hydroxide. This would actually give them dual alkali systems with the attendant advantage of eliminating a liquid waste stream.

Dual alkali. Table 3 shows that dual alkali systems have become the second most prevalent type of SO_2 control for industrial boilers. They may become the first choice as more sodium alkali systems are converted to dual alkali in the face of new regulations that may limit disposal of liquid wastes containing large amounts of dissolved salts.

Dual alkali processes, like lime/limestone slurry scrubbing, are throwaway systems. In the operation as a whole, lime is consumed to produce a wet solid waste (mainly calcium sulfite/sulfate) just as in lime slurry scrubbing. In addition, however, dual alkali systems require a small amount of sodium alkali makeup.

A solution of sodium sulfite/bisulfite and sulfate in a scrubber will absorb SO_2 from the flue gas or other waste gas. Only the sulfite is active in absorbing SO_2, forming bisulfite as in the Wellman-Lord system:

Absorption: $$SO_3^{=} + SO_2 + H_2O \rightarrow 2\ HSO_3^{-} \quad (8)$$

The bisulfite-rich liquor, treated with lime in a reaction tank, regenerates active alkali for recycle to the scrubber:

Regeneration:

$$2\ HSO_3^{-} + Ca(OH)_2 \rightarrow SO_3^{=} + CaSO_3\downarrow + 2\ H_2O \quad (9)$$

$$SO_4^{=} + Ca(OH)_2 \rightarrow 2\ OH^{-} + CaSO_4\downarrow \quad (10)$$

The sulfate and sulfite precipitate as a hydrated mixed crystal, or as a gypsum phase ($CaSO_4 \cdot 2\ H_2O$) plus a hydrated mixed crystal, depending upon the concentration of dissolved species. Also, depending upon solution concentrations, the mixed crystal is predominantly calcium sulfite, with up to about 25% calcium sulfate coprecipitated. Sulfite/bisulfite oxidation by oxygen in the flue gas produces sulfate in the system.

CURRENT STATUS OF U.S. FGD TECHNOLOGY

Application of FGD for control of fossil-fuel-fired utility and industrial boilers has increased dramatically during the 1970's in response to the Clean Air Act and its amendments and the rapidly escalating price of fuel oil. Tables 2 and 3, presented earlier, listed a number of types of FGD processes operating on both utility and nonutility boilers. Table 4, which summarizes these data, also lists the numbers and collective capacity of units that are either under construction or planned.

It is interesting to note that about 40% of the tabulated utility units are in the planned category, while only about 7% of the total industrial boiler systems are in this category. Rather than representing an actual trend, this probably reflects the difficulty in determining industry plans, particularly for the smaller boiler systems, than in determining plans for larger boilers on regulated utility systems.

Based on current controlled capacity, 96% of the operating utility processes and 100% of the nonutility processes are throwaway systems. Although only 3% of the utility systems (the soda ash systems) produce a sizable liquid waste stream, 83% of the nonutility applications (soluble alkali, throwaway) produce such a stream. In general, disposal of large volumes of liquid wastes containing soluble solids is environmentally unacceptable. Also, the cost of soluble alkali reagents is higher than of calcium-based alkali. In most cases a permit for such operations must be secured from the appropriate regulatory authority. Because utility systems are generally larger than nonutility systems, discharge permits for such operation are more difficult to obtain and reagent cost considerations also become more significant. As we aim toward zero discharge, these once-through, soluble scrubbing systems will become less prevalent.

FGD Growth Trends

In the past, fuel consumption has grown at a high rate in the United States. Production of electricity, for example, was growing at about 7% annually (or doubling every 10 years) before the Arab oil embargo in 1973. Since then there has been a reduction in the growth of fuel consumption, in part due to conservation and improved efficiency.

According to an energy use projection model proposed by Data Resources, Inc., the national energy consumption for the year 2000 will be about double what it was for 1975 (5). This could well be a conservative estimate, in that it is based on a Gross National Product increase of 3.7% per year and only a 3% per year energy consumption increase between 1975 and 2000. Further, the increase in electricity generation in this model is 5.3% per year compared with 7% per year in the past. As a result, while energy consumption in the economy may double in the next quarter century, electricity production may almost quadruple.

If the push toward the use of coal to supply our energy requirements continues, it is logical to assume that utilities will play a major role in increasing coal usage. The Federal Power Commission projects an electric utility growth rate of 5.56% through 1995. It also estimates that 50.3% of the generating capacity in 1995 will be fossil fuel fired (6). Assuming a negligible number of oil and natural gas generating units in 1995, and given the fact that about 45% of our present generating capacity is coal fired, it can be concluded that coal-fired power plants will produce about the same or a somewhat greater proportion of our electric power by the end of the century. All of this indicates a growing need for FGD.

Based on the EPA Utility FGD Survey (1) and taking into account specific known FGD systems now in operation, currently under construction, and in various stages of planning, we can project about 59,000 MW of generating capacity being controlled by FGD systems by 1986. As previously mentioned, in mid-1978 there was about 13,000 MW of FGD-controlled utility generating capacity.

It is more difficult to project the nonutility boiler FGD applications because plans for construction are not announced as far in advance. In addition, many industrial boilers in operation and planned are too small to be covered by present Federal and state NSPS.

With utility boilers, however, assuming an annual growth rate of 5.5% for coal-fired boilers through 1990 and further assuming that with revised NSPS (1978 revision) all new coal-fired boilers will be controlled by FGD after 1983, the projected applications of FGD are 87,000 MW of control by 1985 and about 176,000 MW by 1995.

Figure 1 shows a plot of the growth of utility FGD applications between 1968 and 1978, together with projections of known, currently planned FGD applications and projected applications of FGD, assuming all coal-fired boilers would be controlled after 1983. This projection would be reasonable with revised NSPS requiring 85 to 90% SO_2 removal.

FGD System Performance

The main concerns about use of FGD are its dependability (on-stream performance) and costs. As with any new technology, operating problems have become evident due both to design and manner of operation. Greater experience in design and operation improve the dependability of the systems. Costs are discussed in the next section and on-stream performance is discussed here.

Many parameters can be defined and calculated as indices of a system's dependability, and each parameter is probably suited to a slightly different viewpoint. Four such indices are discussed in the EPA Utility FGD Survey reports and are defined below:

Availability--Hours the FGD system was available for operation divided by hours in the period.

Operability--Hours the FGD system was operated divided by boiler operating hours in the period.

Reliability--Hours the FGD system was operated divided by hours it was called upon to operate

Utilization--Hours the FGD system was operated divided by hours in the period.

The dependability of FGD systems for which data were available is plotted in Figure 2 as a function of startup date.

The most appropriate parameter or parameters provided by the utility were plotted. Although there is a scatter in the results, the trend line, which is a least squares regression fit, reflects greatly improved performance of the technology since the early 1970's. This improved performance is attributable to several general process

design and application considerations. It is difficult, if not impossible, to quantify the impact of many of these factors (particularly when attempting to apply such an analysis to the entire spectrum of operating FGD systems); however, several factors can be identified as contributing to this increased performance.

Process design strategy. Recent systems have been designed to incorporate an increased degree of flexibility and reliability (e.g., increased sparing of modules and ancillary components).

System applications. Many of the recent FGD facilities are installed on large, base-loaded units that are designed to fire coal from specific sources. This results in a flue gas with more constant and stable characteristics; thus the system does not have to respond to as dramatic a variation in flue gas flow rate and flue gas composition.

System supplier and architectural-engineering experience. Later FGD system designs have benefitted from experience gained in the operation of first generation systems.

Utility experience. Along with the increased experience being gained by the system suppliers and architectural-engineering firms, utility personnel have been gaining valuable operating and design experience. Many utilities have operated pilot-scale FGD systems and have thus been better prepared for operation of full-scale systems.

Regulatory agency attitudes. As FGD technology has evolved from a research, development, and demonstration effort to a means of continuous compliance, enforcement attitudes by local, state, and Federal regulatory agencies have changed accordingly, compelling utility companies to improve the reliability of FGD systems.

Process chemistry. Although chemical-related problems (scaling and corrosion) are still encountered and, in some cases, are still very severe, general knowledge concerning chemical mechanisms and means of prevention has greatly increased. As a result, systems are being designed and operated so that they will not encounter the same problems experienced by the earlier units.

COST OF FGD SYSTEMS

So many factors affect the costs of installation (capital cost) and operation (annualized operating costs) of FGD systems that it is difficult to arrive at a single, accepted set of figures. Some of the factors affecting capital costs are type of system, design efficiency, materials of construction, process variation, extent of redundancy, site specific requirements, new or retrofit, size of system, and method of disposal of wastes. Similarly, some factors affecting annualized operating costs are interest charges on capital, fuel sulfur content, removal efficiency, cost of labor, cost of reagents, byproduct credit, hours of operation of the boiler, and life expectancy of the system.

In the electric utility industry, capital costs are typically expressed in cost per unit of plant capacity ($/kw.) and annualized operating costs are expressed in cost per unit of power output (mills/ kw.-hr.). The annual cost can be viewed as the additional cost of production of a kilowatt-hour of power attributable to the FGD system. It includes capital cost by amortizing the initial investment for the FGD plant over the expected life of the plant and allocating a portion of this cost to each unit of energy output.

Two basic approaches may be taken in an attempt to project FGD costs. (1) Use actual costs for systems already operating, and (2) use engineering design and cost estimating techniques (based to some extent on experience) to arrive at generalized costs based on given sets of conditions. Since October 1976, PEDCo has reported the costs of FGD systems in the bimonthly EPA Utility FGD Survey Report. These costs were reported essentially as received from the utilities with little or no interpretation. Since March 1978, however, these costs have been analyzed and adjusted to promote better understanding of the individual reported costs and to facilitate economic comparisons among alternative processes. Adjustments focus primarily on the following:

> All capital costs were adjusted to July 1, 1977. Actual costs were reported by utilities in dollar values for the years 1970 to 1980, depending upon the years of system installation. All capital costs, represented in $/kw.,

were expressed in terms of gross megawatts.

Gross unit capacity was used to express all FGD capital expenditures because the capital requirement of an FGD system is dependent on actual boiler size before derating for auxiliary and air quality control power requirements.

Particulate control costs were deducted because the purpose of the study was to estimate the incremental cost for SO_2 control.

All capital costs associated with the modification or installation of equipment necessary, although not a part of the FGD system, were included (e.g., stack lining, modification to existing ductwork or fans).

Indirect charges were adjusted to provide adequate funds for contractor's expenses, engineering, field expenses, legal expenses, taxes, insurance, interest during construction, startup.

Contingency costs were added where necessary (if further improvements to the system were anticipated or where cost data were incomplete).

Annual costs, represented in mills/kw.-hr., were expressed in terms of net generating capacity. Net unit capacity was used to express annual expenditures because the annual cost requirement is dependent on the actual number of kilowatt-hours produced by the unit after derating for auxiliary and air quality control power requirements.

Annual costs were adjusted to a common capacity factor (65%).

Replacement power costs were not included because the few utilities reporting such costs used a variety of methods of present them.

Sludge disposal costs were adjusted to reflect the costs of SO_2 scrubber sludge disposal only (i.e., excluding fly ash disposal) and to provide for disposal over the anticipated lifetime of the FGD system. This latter correction was necessary since several utilities reported costs for demonstration sludge disposal systems that would last only a fraction of the FGD system life.

A 30-year life was assumed in all process and economic considerations for all new systems that were installed for the life of the unit. A 20-year life was assumed in all process and economic considerations for all retrofit systems, even if the expected life of the boiler was less than 20 years.

Regeneration facilities and sulfuric acid or sulfur recovery facility costs were added for those regenerable systems not reporting such costs.

A summary of the reported and adjusted capital and annual costs by system type, with ranges and averages, is given in Table 6.

Generalized costs for most of the FGD systems now in use have been projected by the Tennessee Valley Authority (TVA) using a given set of assumptions (9). Several of these projected costs are given in Table 7 for comparison with reported and adjusted costs; however, because of the many factors that affect costs and the noncommon basis, perfect agreement should not be expected. Nevertheless, a number of comparisons between the reported and adjusted cost data and the TVA generalized cost data can be made for the various system types. The results are briefly summarized below:

Limestone: The average reported and adjusted capital costs of the eight identified units (470-MW average capacity) are 4% lower and 22% higher, respectively, than the TVA capital costs of a 500-MW unit; annual costs are 39% lower and 20% higher than the TVA annual costs.

Lime: The average reported and adjusted capital costs of the identified units (439-MW average capacity) are 24 and 50% higher, respectively, than the TVA capital costs of a 500-MW unit; annual costs are 95.9 and 73.7% higher than the TVA annual cost.

Magnesium oxide: Only one unit, a prototype experimental unit, is in service at the present time. A comparison of its costs with TVA cost data, which provide costs of full-scale

compliance units, is limited; however, the reported and adjusted capital costs are 64 and 144% higher, respectively, than the TVA capital cost of a 200-MW unit.

It should be noted that all the TVA generalized cost data are for new systems, whereas the reported and adjusted cost data include new and retrofit systems. In addition, the TVA costs were generated in March 1976, and since that time TVA has published more recent cost data (10). These economic evaluations were developed using updated design and economic premises for a citrate process (U.S. Bureau of Mines type), a generic double alkali process, and a limestone process. Because no citrate or double alkali utility systems are currently in service, comparisons are only possible with the limestone process. The updated TVA capital and annual costs of a 500-MW limestone system are $83.3/kw. and 3.44 mills/kw.-hr.* The average reported and adjusted capital costs of the eight operational limestone systems are 20.9 and 0.2% lower, respectively, than the updated TVA capital cost; the annual costs are 39.5% lower and 19.2% higher than the updated TVA annual cost. Thus, the reported and adjusted capital and annual costs show closer agreement with the updated TVA costs, which for limestone increased (disregarding inflation) approximately 22% over TVA's March 1976 costs. Furthermore, if this trend is assumed to apply to the other processes addressed in the March 1976 TVA cost study, comparison with the reported and adjusted operational system costs should also show a correspondingly closer agreement for lime systems and a somewhat closer agreement for magnesium oxide systems. These results are briefly summarized below:

Lime: The average reported and adjusted capital costs are 2 and 23% higher, respectively, than the projected updated TVA capital costs of a 500-MW unit ($74.5/kw.); annual costs are 94 and 72% higher than the projected updated TVA annual cost ($3.68 mills/kw.-hr.).

Magnesium oxide: The reported and adjusted capital costs of the one operational system identified are 34 and 100% higher, respectively, than the projected updated TVA capital cost for a 200-MW unit ($116.6/kw.).

Based on a cost of 3 cents/kw.-hr. for generation of electricity and TVA's projected annualized operating costs of new 500-MW plants in 1978, the percentage increases in cost of generation of electric power attributable to FGD are 11% for a limestone system, 12% for a lime system, 13% for a magnesium oxide system, and 18% for a Wellman-Lord/Allied Chemical system. The impact on total system wide production costs (which of the total power is supplied by existing reflect in costs to the consumer) is usually considerably less because a large percentage of the total power is supplied by existing units that do not require FGD systems. The total impact on systemwide production costs has been estimated to range between 3 and 5%.

CURRENT STATUS OF JAPANESE FGD TECHNOLOGY

Background

Application of FGD systems in Japan has shown remarkably rapid progress since 1972, as shown in Figure 3. This growth rate can be largely attributed to the elimination of the previous sizable cost differential between FGD and low-sulfur fuels and the increasing confidence in the reliability of FGD system operation. This growth rate, however, began to decline recently for the following reasons:

Ambient SO_2 concentrations in large cities and industrial districts have been reduced to the ranges of 0.02 to 0.03 p.p.m., almost achieving the ambient annual standard of 0.016 p.p.m.

The recent downturn in the Japanese economy has restricted the building of new plants. The majority of the FGD systems were built between 1970 and 1975 when the Japanese economy was growing rapidly.

Saturation of the FGD byproduct market and a decrease in the price differen-

*The TVA generalized cost data published in November 1977 provide all capital and annual costs in mid-1979 dollars. Using the average annual Chemical Engineering cost indexes employed by the TVA model, all costs were deescalated by PEDCo to mid-1977 dollars.

tial between high-sulfur and low-sulfur oil have resulted in more extensive use of low-sulfur fuels because Japan has little area available for discarding waste products.

Stringent NO_x emission standards have resulted in the development of a number of processes for simultaneous removal of NO_x and SO_x. Rather than installing separate systems for NO_x and SO_x control, much of the industry is waiting for this new technology to be fully demonstrated.

Nevertheless, the present government policy of increased use of coal (much of it imported for power production) will necessitate the use of additional FGD systems in the future. Three new coal-fired utility units totaling 1175 MW that will use limestone-gypsum processes are presently under construction and are scheduled for startup in 1979 or 1980.

More than 500 major FGD plants having a combined capacity of 90,000,000 $Nm^3/hr.$ (29,600 MW equivalent) were operational in Japan at the beginning of 1978. Table 8 summarizes these systems by constructor, process type, and capacity. Approximately half of the total capacity represents utility boiler application (primarily oil fired) and the remainder includes industrial boilers, sintering plants, smelters, and sulfuric acid plants.

About 49% of the plant capacity uses the lime/limestone process producing usable gypsum; 16% uses the indirect lime/limestone process (dual alkali type); 13% uses regenerable processes that yield sulfuric acid, elemental sulfur, and ammonium sulfate as byproducts; and 22% uses sodium scrubbing that yields sodium sulfite or sulfate as a byproduct. The average plant size is 427,000 $Nm^3/hr.$ for the lime/limestone systems, 291,000 $Nm^3/hr.$ for indirect lime/limestone systems, 378,000 $Nm^3/hr.$ for the regenerable processes, and 59,600 $Nm^3/hr.$ for the sodium scrubbing plants. Around 80% of the sodium scrubbing units yield sodium sulfite for use in paper mills, and the rest oxidize the sulfite to sulfate either for use in the glass industry or disposal as wastewater.

In addition to the 392 sodium scrubbing units shown in Table 8, there are about 500 small commercial sodium scrubbing systems having an average capacity of 20,000 $Nm^3/hr.$

Status of FGD in the Japanese Utility Industry

As shown in Table 9, nine major private utility companies have produced about 70% of the total steam electric power generated in Japan, largely using imported oil. The Electric Power Development Co. (EPDC) has been the primary consumer of domestic coal for power production; however, coal-fired utility capacity presently accounts for less than 3% of the steam electric power produced. The total capacity of the utility steam electric generating industry (including those plants under construction) is 87,475 MW. This figure represents about 75% of the total utility power generated in Japan, with hydroelectric and nuclear power representing 20% and 5%, respectively.

The present FGD utility capacity in service in Japan stands at 10,076 MW, with another 3750 MW under construction or planned. This represents about 16% of the utility industry steam generating capacity. Comparable figures for U.S. utilities show 12,112 MW of FGD capacity in operation with an additional 46,832 MW under construction or planned, or about 24% of the total U.S. coal-fired power generating capacity.

Among the major power companies, Tokyo Electric, Kansai Electric, and Chubu Electric supply power to the largest cities and industrial complexes in Japan. As shown in Table 9, these companies have elected to use low-sulfur fuels such as naphtha and liquefied natural gas (LNG) in heavily polluted sections of their service areas, apparently because they are concerned that SO_2 emission standards may be further tightened beyond the point easily achievable by FGD. Recent regulations restricting total SO_2 mass emissions require large power plants in designated regions to maintain stack SO_2 outlet concentrations below 50 p.p.m., thus necessitating the use of low-sulfur fuel for reheat. More stringent standards may reduce the use of FGD as an effective control strategy. Conversely, Hokuriku Electric has power plants more remotely located from the large cities and, hence, has a larger percentage of its capacity using FGD systems.

Table 10 lists all FGD systems installed at power plants in Japan.

Comparison With U.S. FGD Systems

Application of FGD Systems in Japan has generally preceded application in the United States because serious air pollution problems in the 1960's resulted from a high concentration of industry near major Japanese population centers. Over 500 major FGD plants having a combined equivalent capacity of 27,500 MW are presently in operation in Japan. About half of this total represents utility boiler applications (predominantly oil fired), 98% of which produce usable gypsum from lime/limestone or double alkali FGD processes.

FGD technology is working well in Japan on both utility and industrial applications. The performance of the coal-fired units (90+% SO_2 removal efficiency, 95+% availability) has not been appreciably different from that of their oil-fired or industrial counterparts with respect to SO_2 removal efficiency and scrubber system reliability. This outstanding performance is typical of that generally reported for other FGD systems.

The successful operation of lime/limestone scrubbers in Japan has been attributed partially to open-loop operation, which is created by purging large quantities of process liquids. The extent of liquid blowdown, however, is variable; water removed from a Japanese lime/limestone scrubber system via the gypsum produced and liquid purged is often quite similar in quantity to that removed with the sludge in a typical closed-loop U.S. scrubber system that uses ponding.

A number of differences that are apparent in the development and application of FGD technology in Japan and the U.S. are summarized below:

The Japanese system suppliers and operators recognize and accept the fact that FGD systems basically involve chemical processes requiring carefully controlled operation by personnel specifically trained for this purpose.

The design of FGD systems in Japan appears to have generally been approached with a more conservative philosophy than that in the United States. The user expects and, in fact, demands that the FGD system supplied perform with a reliability compatible with that of the power generating plant. This philosophy has generally resulted in scrubber systems that are initially more expensive than their U.S. counterparts but that have required less subsequent modification and maintenance as a result of fewer operating problems.

The range of sulfur content of the coal burned in Japanese utility and industrial boilers is significantly lower than that used in many U.S. power generating systems. Japanese FGD systems have generally been used on flue gases having SO_2 inlets of 400 to 2300 p.p.m. This range of inlet sulfur values is experienced by many scrubber systems applied to U.S. coal-fired utility boilers; however, there is no experience in Japan with the higher sulfur coals currently used in conjunction with many U.S. utility FGD systems.

Japan follows a stringent continuous monitoring and enforcement program to insure that utility and industrial sources are in compliance with environmental regulations.

In some areas where the ambient concentration of SO_x is considered to be sufficient to cause health problems, an SO_x emission tax has been levied. These tax proceeds have been used for the medical care of patients diagnosed as having pollution-related illnesses, such as chronic bronchitis.

The last difference can best be expressed as the sincere cooperative spirit that appears to exist between Japanese industry and the regulatory agencies. The need for environmental controls for SO_x was at the crisis level in the late 1960's when Japan's FGD installation program began to accelerate. The national goal of a cleaner environment has been accepted by the utility industry, which has made a sincere effort to buy the best scrubbers available and to operate them in the manner for which they were designed.

FEDERAL RESEARCH, DEVELOPMENT, AND DEMONSTRATION PROGRAMS

The 1970 and 1977 amendments to the Clean Air Act provide the authority for the research, development, and demonstration program now being conducted by the EPA Industrial Environmental Research Laboratory (IERL-RTP), Research Triangle Park, North Carolina. The primary purpose of this program has been to improve, develop, and demonstrate reliable, cost-effective, and environmentally acceptable FGD processes for reducing SO_x emissions from both existing and new stationary combustion sources.

The EPA has been aided in this effort by at least two other Federal organizations, TVA and the U.S. Bureau of Mines (USBM). For example, EPA's key program in the nonregenerable area is the lime/limestone prototype test program at TVA's Shawnee Steam Plant (near Paducah, Kentucky), and a major regenerable citrate demonstration unit is being built at a St. Joe Minerals plant based on pilot plant work by USBM.

Some of the more significant current Federal FGD programs are summarized below.

The Shawnee Program Lime/Limestone Utility Prototype Testing

An important part of the lime/limestone development effort involves the operation of a prototype scrubbing test facility, the TVA Shawnee Steam Plant. This versatile facility allows comprehensive testing of two 10-MW scrubbers under a variety of conditions. Bechtel Corporation of San Francisco designed the test facility and directs the test program. The TVA constructed and operates the facility.

Major objectives of the original 2-year test program were to characterize fully the effect of important process variables on SO_2 and particulate matter removal, to develop and verify mathematical models to allow scaleup to full-scale scrubber facilities, to study the technical and economic feasibility of lime/limestone scrubbing, and to demonstrate long-term reliability. Later the Shawnee program was expanded to investigate promising equipment and process variations designed to minimize costs, energy requirements, and quantity (and improve the quality) of the sludge produced; to develop a design/economic study computer program; and to improve system control and operating reliability, especially in the mist eliminator area. Of particular interest were studies of forced oxidation, increased alkali utilization, and MgO or other additives to increase SO_2 removal efficiency and to force subsaturated gypsum operation (12).

The EPA Pilot FGD Scrubber Program

The FGD pilot plant at IERL-RTP consists of two scrubbers having a flue gas capacity of about 0.1 MW. They have been in operation since 1972 to provide in-house experimental support for EPA's larger, prototype-scrubber test facility at the Shawnee Steam Plant. The IERL-RTP scrubbers have 1% of the capacity of the Shawnee prototypes and are 1/1000 the size of a small, full-scale utility system. In addition to supporting Shawnee, the pilot plant also provides IERL-RTP with the capacity to evaluate independently new concepts in lime/limestone scrubbing technology. Many of the new concepts tested at Shawnee were first conceptualized and developed in the IERL-RTP pilot plant.

Rickenbacker Air Force Base--Industrial Boiler FGD System

EPA has sponsored an 18-month test program at a lime/limestone industrial boiler FGD system installed to control SO_2 particulate emissions from several small, coal-fired heating boilers (approximately 23 MW equivalent, total) at the Rickenbacker Air Force Base near Columbus, Ohio. The FGD system was installed under contract between the Air Force and Research Cottrell, the licensee for the A.B. Bahco lime/ limestone scrubbing process. This process was developed by A.B. Bahco, a Swedish company, and is reported to be particularly well suited for industrial boiler applications because it is manufactured in standard sizes in the range of 5 to 50 MW (equivalent) and is adaptable to a high degree of automation. The application of the Bahco scrubber at Rickenbacker was the first such installation in the United States and the first anywhere on a coal-fired industrial boiler.

Although numerous mechanical problems have been encountered since startup in March 1976, the operation has improved to the extent that 95% availability has been demonstrated for about 6 months. There were no problems with scale formation or plugging with either lime or limestone, and the

system easily met or exceeded all emission and operating cost guarantees. A final report on this program is currently being prepared.

Louisville Gas & Electric (LG&E) Lime Scrubbing Test Program

In the spring of 1976, a test program was initiated at the Paddy's Run plant of LG&E. Some of the objectives of the program were to compare carbide lime with ordinary commercial lime in the operation of a full-scale system, to test the gypsum subsaturated mode of operation with both absorbents, and to investigate the effects of magnesium oxide and chloride addition to the system. Scrubber testing took place between the fall of 1976 and the summer of 1977, with Radian conducting the system analysis and evaluation.

It was found that, whereas subsaturated operation was achieved with carbide lime, similar operation with commercial lime did not give the same result. A major finding of the program was that carbide lime contained trace quantities of an oxidation inhibitor (suspected to be thiosulfate), which promoted subsaturated operation. Subsaturated operation was eventually achieved at LG&E with commercial lime with the addition of magnesium oxide in small quantities.

Final reports on both the LG&E scrubber testing and carbide lime characterization studies are being prepared for general publication.

Louisville Gas & Electric Full-Scale Dual Alkali Demonstration

In September 1976, EPA contracted with LG&E for a cost-shared, full-scale, coal-fired utility demonstration of the dual alkali process at the 280-MW Cane Run No. 6 boiler. The demonstration project consists of four phases: (1) design and cost estimation; (2) engineering design, construction, and mechanical testing; (3) startup and performance testing; and (4) 1 year of operation and long-term testing. Construction is expected to be complete by the end of 1978, and testing will begin in early 1979.

A report on the Phase 1 preliminary design and cost estimate for the system was published in January 1978 (13). In addition to the design and cost estimate for the LG&E system, it also gives cost projections for similar hypothetical systems in the 500- through 1000-MW range. The report projects the LG&E system costs at less than $60/kw. capital cost and less than 3 mills/kw.-hr. annualized operating costs in 1976 dollars.

Wellman-Lord/Allied Chemical Demonstration Program

The EPA and Northern Indiana Public Service Company (NIPSCO) have jointly funded the design and construction of an FGD demonstration plant using the Wellman-Lord SO_2 recovery process and the Allied Chemical SO_2 reduction process to convert recovered SO_2 to elemental sulfur. The operational costs for the system will be paid by NIPSCO, and a comprehensive test and evaluation program, conducted by TRW Corporation, will be funded by EPA. The demonstration system has been retrofitted to the 115-MW, coal-fired Unit 11 at the Dean H. Mitchell Station in Gary, Indiana.

The demonstration program consists of three phases. Phase I--the development of a process design, major equipment specification, and a detailed cost estimate--was completed in December 1972; Phase II--the final design and construction--was completed by Davy Powergas, Inc., in August 1976; and Phase III--the long-term test and evaluation--is currently underway.

Between August 1976 and August 1977, various problems involving both the boiler and the FGD system (primarily the boiler) delayed the acceptance tests. System performance exceeded all performance criteria tested including SO_2 removal (91% attained, 90% required), particle emissions, utility costs, sodium carbonate consumption, and sulfur product purity.

Aqueous Carbonate Demonstration Program

The EPA and Empire State Electric Energy Research Corporation (ESEERCO), a research organization sponsored by New York's eight major power suppliers, have contracted to fund jointly the design and construction of a demonstration of the Atomics International sulfur-producing aqueous carbonate process. The demonstration is being retrofitted to a 100-MW boiler at Niagara Mohawk Power Company's coal-fired Huntley Station in Tonawanda, New York.

The demonstration will be in four phases. Phase I, the design and cost estimate, was completed in May 1977. Phase II, construction, is expected to begin by the end of 1978. Phase III, acceptance testing, and Phase IV, demonstration testing, will follow.

U.S. Bureau of Mines Citrate Demonstration Program

The EPA and USBM have entered into a cooperative agreement to demonstrate the citrate process, a regenerable sulfur producing process that has been developed on a pilot scale by USBM. A concurrent development program, carried out by an industrial consortium headed by Pfizer Chemical Company, also led to a pilot operation of the process. Based on the results of these two pilot programs, EPA and USBM have initiated the demonstration of this technology on a 50-MW coal-fired boiler at St. Joe Mineral Corporation in Monaca, Pennsylvania.

The demonstration will be in four phases. Phase I, the design and cost estimate, was completed in November 1976. Phase II, detailed design, procurement, and construction, began in March 1977 and is scheduled to be completed in October 1978. Acceptance testing, Phase III, should be accomplished by the end of 1978, at which time a 1-year test and evaluation program, Phase IV, will be initiated.

CONCLUSIONS

The projected increase in the use of high-sulfur coal in the coming years will be accompanied by a corresponding increase in the emissions of SO_x. Because of the limitations of the low-sulfur coal and coal cleaning options, application of FGD technology is playing a critical control role because it is the best near-term option available for quick reduction of SO_x emissions in compliance with the Clean Air Act Amendments.

Several important emerging technologies, including fluidized-bed combustion, will offer attractive alternatives to the use of FGD, however, they will probably not make significant commercial impact prior to 1985.

The Federal Interagency FGD program, conducted in conjunction with the private sector, has been instrumental in furthering the development, demonstration, and application of FGD technology. Utility application of FGD systems presently includes nearly 59,000 MW of capacity either in operation, under construction, or planned. Although some technical problems still persist at certain installations, the general dependability of FGD systems has steadily improved during the past several years as the technology has matured.

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TABLE 1. NATIONAL AMBIENT AIR QUALITY STANDARDS FOR SO_2

Concentration	Primary	Secondary
Annual mean	80 μg/m³ (0.03 p.p.m.)	
Maximum 24-hour[a]	365 μg/m³ (0.14 p.p.m.)	
Maximum 3-hour[a]		1300 μg/m³ (0.5 p.p.m.)

[a] Not to be exceeded more than once a year.

TABLE 2. OPERATING UTILITY FGD SYSTEMS[a]

Process	No. of units	Controlled generating capacity, MW	Capacity, % of total
Limestone	11	4,813	38
Limestone/alkaline fly ash	2	1,420	11
Lime	13	4,515	35
Lime/alkaline fly ash	3	1,170	9
Soda ash	3	375	3
Magnesium oxide	1	120	1
Wellman-Lord/ Allied Chemical	2	429	3
Totals	35	12,842	100

[a] Two prototype units, 10-MW each, were deleted from this table because they were not considered full-scale utility systems.

Source: Ref. 1.

TABLE 3. OPERATING NONUTILITY FGD SYSTEMS

Process	Controlled capacity			
	No. of units	acfm	Equivalent MW[a]	Capacity, % of total
Soluble alkali, throwaway (Na, NH_3, alkaline waste)	27	4,360,000	1362	83
Dual alkali	5	542,000	169	10
Lime	1	280,000	88	5
Limestone	1	73,000[b]	23	2
Totals	34	5,255,000	1642	100

[a] 3200 acfm (actual cubic feet/min.) = 1 MW.

[b] Estimated to conform with other figures in the table.

Source: Ref. 2.

TABLE 4. SUMMARY OF UNITED STATES FGD SYSTEMS

Status	Utility boilers		Industrial boilers		
				Capacity	
	No. of units	Capacity, MW	No. of units	10^3 acfm	Equivalent MW[a]
Operational	35[b]	12,842[b]	34	5232	1635
Under construction	43	17,177	5	1636	511
Planned	58	28,905	3	788	247
Total	136	58,924	42	7656	2393

[a] 3200 acfm (actual cubic feet/min.) = 1 MW.

[b] Two prototype units, 10-MW each, were deleted from this table because they were not considered full-scale utility systems.

Sources: Ref. 1 and 2.

TABLE 5. IDENTIFICATION OF PLANTS IN FIGURE 2[a]

1	Will County Commonwealth Edison	12	Green River 1, 2, and 3 Kentucky Utilities
2	Mystic Boston Edison	13	Colstrip 1 Montana Power
3	Hawthorn 4 Kansas City Power and Light	14	Sherburne 1 Northern States Power
4	Hawthorn 3 Kansas City Power and Light	15	Bruce Mansfield 1 Pennsylvania Power
5	La Cygne 1 Kansas City Power and Light	16	Cane Run 4 Louisville Gas and Electric
6	Paddy's Run 6 Louisville Gas and Electric	17	Colstrip 2 Montana Power
7	Cholla 1 Arizona Public Service	18	Reid Gardner 3 Nevada Power
8	Reid Gardner 2 Nevada Power	19	Conesville 5 Columbus & Southern Ohio Electric
9	Reid Gardner 1 Nevada Power	20	Sherburne 2 Northern States Power
10	Scholz 1A Gulf Power	21	Widows Creek 8 Tennessee Valley Authority
11	Scholz 1B and 2B Gulf Power	22	Bruce Mansfield 2 Pennsylvania Power

[a] The plants that appear in this table and in Figure 2 are selected solely on the availability of meaningful quantified performance data. A number of plants are excluded, therefore, because performance records, or performance data from which this information can be derived, either are not kept by the owning/operating utilities or are not available. In addition, a number of plants that contain FGD systems that have recently ceased operation are also excluded because of the lack of meaningful operating data.

TABLE 6. COSTS OF OPERATING UTILITY FGD SYSTEMS

System type (number reported)	Size, MW		Reported costs				Adjusted costs			
			Capital,[a] $/kw.		Annual,[b] mills/kw.-hr.		Capital,[a] $/kw.		Annual,[b] mills/kw.-hr.	
	Range	Average	Range	Average	Range	Average	Range	Average	Range	Average
Limestone[c] (8)	115-820	470	47.5-99.5	65.9	1.61-3.00	2.08	56.0-117.1	83.1	2.58-6.56	4.10
Lime[c] (14)	64-825	439	27.0-120.7	76.0	0.27-14.35	7.15	67.5-149.7	91.7	4.06-9.54	6.34
Soda ash (3)	125	125	42.9-113.6	66.5	2.10	2.10	60.9-107.9	78.5	3.20-4.38	3.59
MgO[d] (1)	108	108	156.8	156.8			233.3	233.3		

[a] Capital costs, represented in $/kw., are expressed in terms of gross unit capacity.

[b] Annual costs, represented in mills/kw.-hr. are expressed in terms of net unit capacity.

[c] The alkaline fly ash systems that use limestone and lime as supplemental reagents are included in the limestone and lime system types.

[d] Only the reported and adjusted capital costs are currently available for this experimental system, which controls about one-third of the flue gas from the 316-MW boiler.

Source: Ref. 1.

TABLE 7. TVA PROJECTED CAPITAL AND ANNUALIZED OPERATING COSTS[a]

System type	Size, MW	Capital cost, $/kw.	Annualized operating cost, mills/kw.-hr.
Limestone	200	88.4	4.20
	500	68.4	3.41
	1000	51.4	2.74
Lime	200	79.9	4.54
	500	61.1	3.65
	1000	44.9	2.94
MgO	200	95.6	5.03
	500	71.7	4.02
	1000	53.0	3.26
Wellman-Lord/Allied Chemical	200	112.0	6.60
	500	84.8	5.37
	1000	64.2	4.46

[a] Basis:

(1) New coal-fired power plant, 3.5% S coal, Midwest plant location.
(2) Average cost basis, 1977. Construction, 1975-1978.
(3) Minimum process storage; only pumps spared.
(4) Working capital is included in total investment.
(5) For throwaway systems, sludge disposal in onsite, clay-lined pond.
(6) 30-year plant life, 7000 hr./year operation.
(7) Byproduct credit and sludge fixation costs excluded.
(8) 90% SO_2 removal.

TABLE 8. NUMBERS AND CAPACITIES (1000 $Nm^3/hr.$) OF JAPANESE FGD PLANTS BY MAJOR CONSTRUCTORS

Plant constructor	Process type								Total	
	Lime/limestone[a]		Indirect lime/limestone[a]		Regenerable		Once-through sodium			
Mitsubishi Heavy Industries (MHI)	33	(18,270)					3	(292)	36	(18,562)
Ishikawajima H.I. (IHI)	17	(4,445)					79	(4,351)	96	(8,796)
Hitachi, Ltd.	13	(6,940)			2	(590)	15	(603)	30	(8,133)
Mitsubishi Kakoki (MKK)	2	(256)			13	(6,478)	41	(913)	56	(7,643)
Kawasaki Heavy Industries	4	(756)	6	(5,450)			7	(256)	17	(6,380)
Tsukishima Kikai (TSK)	1		4	(398)	1	(88)	40	(4,042)	46	(4,528)
Chiyoda Chemical Engineering & Construction			14	(4,459)					14	(4,459)
Oji Koei							57	(4,280)	57	(4,280)
Fuji Kasui Engineering	7	(3,954)					6	(270)	13	(4,224)
Kurabo Engineering			5	(413)	1	(18)	106	(3,751)	112	(4,182)
Mitsui Miike-Chemico	4	(2,744)			1	(500)			5	(3,244)
Ebara Manufacturing			11	(1,914)			10	(1,167)	21	(3,081)
Nippon Kokan (NKK)	3	(245)	1	(150)	2	(1,990)	6	(62)	12	(2,447)
Kureha Chemical							8	(1,431)	8	(1,431)
Showa Denko							5	(1,372)	5	(1,372)
Gadlius							8	(1,291)	8	(1,291)
Sumitomo (SCEC)-Wellman					6	(1,288)			6	(1,288)
Mitsui Metal Engineering	4	(1,006)			2	(130)			6	(1,136)
Kobe Steel	5	(1,125)							5	(1,125)
Japan Gasoline	1	(330)			1	(125)			2	(455)
Dowa Engineering			5	(453)					5	(500)
Niigata Iron Works			1	(185)					1	(185)
Mitsui Shipbuilding							1	(160)	1	(160)
Sumitomo Heavy Industries					1	(150)			1	(150)
Total	94	(40,171)	47	(13,422)	30	(11,357)	392	(24,241)	563	(89,138)

[a] Gypsum byproduct.

Source: Ref. 10.

TABLE 9. CAPACITIES OF STEAM POWER PLANTS AND FGD SYSTEMS IN JAPAN

Power company	Power generation, MW			FGD, MW			B/A, %
	Existing	Under construction[a]	Total (A)	Existing	Under construction[a]	Total (B)	
Nokkaido	1,270	1,225	2,495	0	525	525	21.0
Tohoku	3,925	1,200	5,125	550	320	900	17.6
Tokyo	19,167	4,400	23,567	283	0	0	1.2
Chubu	9,933	3,800	13,733	970	0	970	7.1
Hokuriku	1,412	1,000	2,412	600	500	1,100	45.6
Kansai	10,672	1,200	11,872	930	0	930	7.8
Chugoku	3,777	1,800	5,777	1,350	700	2,050	36.8
Shikoku	2,687	450	3,137	900	0	900	12.5
Kyushu	4,500	2,700	1,376	1,376	250	1,626	22.6
EPDC	1,430	1,000	2,430	1,280	1,000	2,280	93.8
Niigata	350	350	700	175	175	350	50.0
Showa	550	0	550	400	0	400	72.7
Toyama	750	0	750	250	0	250	33.3
Mizushima	462	0	462	156	0	156	33.8
Sumitomo	368	250	618	156	0	156	25.2
Sakata	0	700	700	700	0	700	100.0
Fukui	0	250	250	0	250	250	100.0
Others	5,512	375	5,887	0	0	0	0.0
Total	66,775	20,700	87,475	10,076	3,750	13,826	15.8

[a] Includes units in the planning stage as well as those currently under construction.

Source: Ref. 10.

TABLE 10. FGD SYSTEMS APPLIED TO POWER PLANTS IN JAPAN

Power company	Power station	Boiler No.	Boiler MW	FGD MW	Process developer	Absorbent, precipitant	Byproduct	Year of completion
Tohoku	Shinsendai	2	600	150	Kureha-Kawasaki	Na_2SO_3, $CaCO_3$	Gypsum	1974
"	Hachinohe	4	250	125	Mitsubishi H.I.	CaO	"	1974
"	Niigata	4	250	125	Wellman-MKK	Na_2SO_3	H_2SO_4	1976
"	Niigata H.	1	600	150	Mitsubishi H.I.	$CaCO_3$	Gypsum	1976
"	Akita	3	350	350	Kureha-Kawasaki	Na_2SO_3, $CaCO_3$	"	1977
Tokyo	Kashima	3	600	150	Hitachi-Tokyo	Carbon, $CaCO_3$	"	1972
"	Yokosuka	1	265	133	Mitsubishi H.I.	$CaCO_3$	"	1974
Chubu	Nishinagoya	1	220	220	Wellman-MKK	Na_2SO_3	H_2SO_4	1973
"	Owase	1	375	375	Mitsubishi H.I.	CaO	Gypsum	1976
"	"	2	375	375	"	"	"	1976
Hokuriku	Toyama	1	500	250	Chiyoda	H_2SO_4, $CaCO_3$	"	1974
"	Fukui	1	350	350	"	"	"	1975
"	Nanao	1	500	500	Not decided	"	"	1978
Kansai	Sakai	8	250	63	Sumitomo H.I.	Carbon	H_2SO_4	1972
"	Amagasaki	2	156	35	Mitsubishi H.I.	CaO	Gypsum	1973
				121	"	"	"	1975
"	"	1	156	156	"	"	"	1976
"	Osaka	3	156	156	Babcock-Hitachi	$CaCO_3$	"	1975
"	"	2	156	156	"	"	"	1975
"	"	4	156	156	"	"	"	1976
"	Kainan	4	600	150	Mitsubishi H.I.	CaO	"	1974
Chugoku	Mizushima	2	156	100	Babcock-Hitachi	$CaCO_3$	"	1974
"	Tamashima	3	500	500	"	"	"	1975
"	"	2	350	350	"	"	"	1976
"	Shimonoseki	2	400	400	Mitsubishi H.I.	"	"	1976
"	"	1	175[a]	175	"	"	"	1979
Hokkaido	Higashitomakomai	1	500	250	Not decided	"	"	1981
Shikoku	Anna	3	450	450	Kureha-Kawasaki	Na_2SO_3, $CaCO_3$	Gypsum	1975
"	Sakaide	3	450	450	"	"	"	1975
Kyushu	Karita	2	375	188	Mitsubishi H.I.	CaO	"	1974
"	Karatsu	2	375	188	"	$CaCO_3$	"	1976
"	"	3	500	250	"	"	"	1976
"	Ainoura	1	375	250	"	"	"	1976
"	"	2	500	250	"	"	"	1976
"	Buzen	1	500	250	Kureha-Kawasaki	Na_2SO, $CaCO_3$	"	1977
"	"	2	500	250	"	"	"	1978
EPDC	Takasago	1	250[a]	250	Mitsui-Chemico	$CaCO_3$	"	1975
"	"	2	250[a]	250	"	"	"	1976
"	Isogo	1	265[a]	265	Chemico-IHI	"	"	1976
"	Takehara	1	250[a]	250	Babcock-Hitachi	"	"	1977
"	Matsushima	1	500[a]	500	Not decided	"	"	1980
"	"	2	500[a]	500	"	"	"	1980
Niigata	Niigata	1	350	175	MHI	"	"	1975
Showa	Ichihara	1	150	150	Showa Denio	$NaSO_3$, CaCO	"	1973
"	"	5	250	250	Babcock-Hitachi	$CaCO_3$	"	1976
Toyama	Toyama	1	250	250	Chiyoda	H_2SO_4, $CaCO_3$	"	1975
[illegible]	Mizushima	5	156	156	Mitsubishi H.I.	CaO	"	1975
Sumitomo	Niihama	3	156	156	IHI	$CaCO_3$	"	1975
Sakata	Sakata	1	350	350	Mitsubishi H.I.	"	"	1976
"	"	2	350	350	"	"	"	1977
Fukui	Fukui	1	250	250	Not decided	"	"	1977

[a] Coal-fired boilers. Others are for oil-fired boilers.

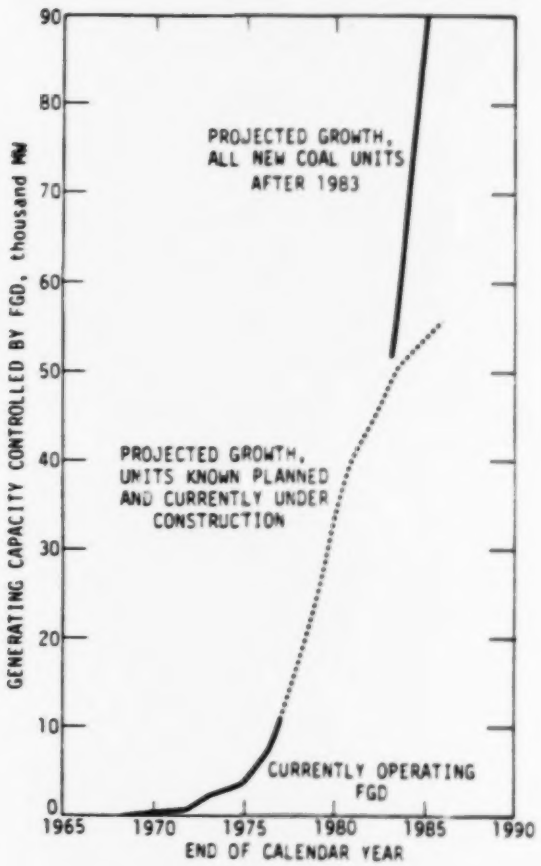

Fig. 1. Present application and projected growth of utility FGD systems.

Sources: Ref. 1 and 7.

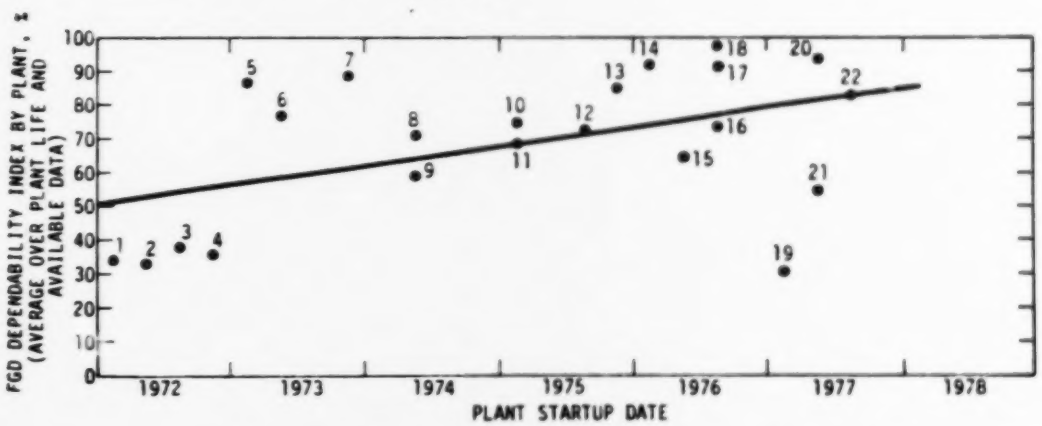

Fig. 2. Average plant FGD dependability index (%),* versus plant startup date through March 1978. (See Table 5 for plant identification.)

Source: Ref. 8.

*FGD dependability index: FGD system availability, reliability, operability, and utilization are the four parameters that are used to characterize the operation of an FGD system during a given period.

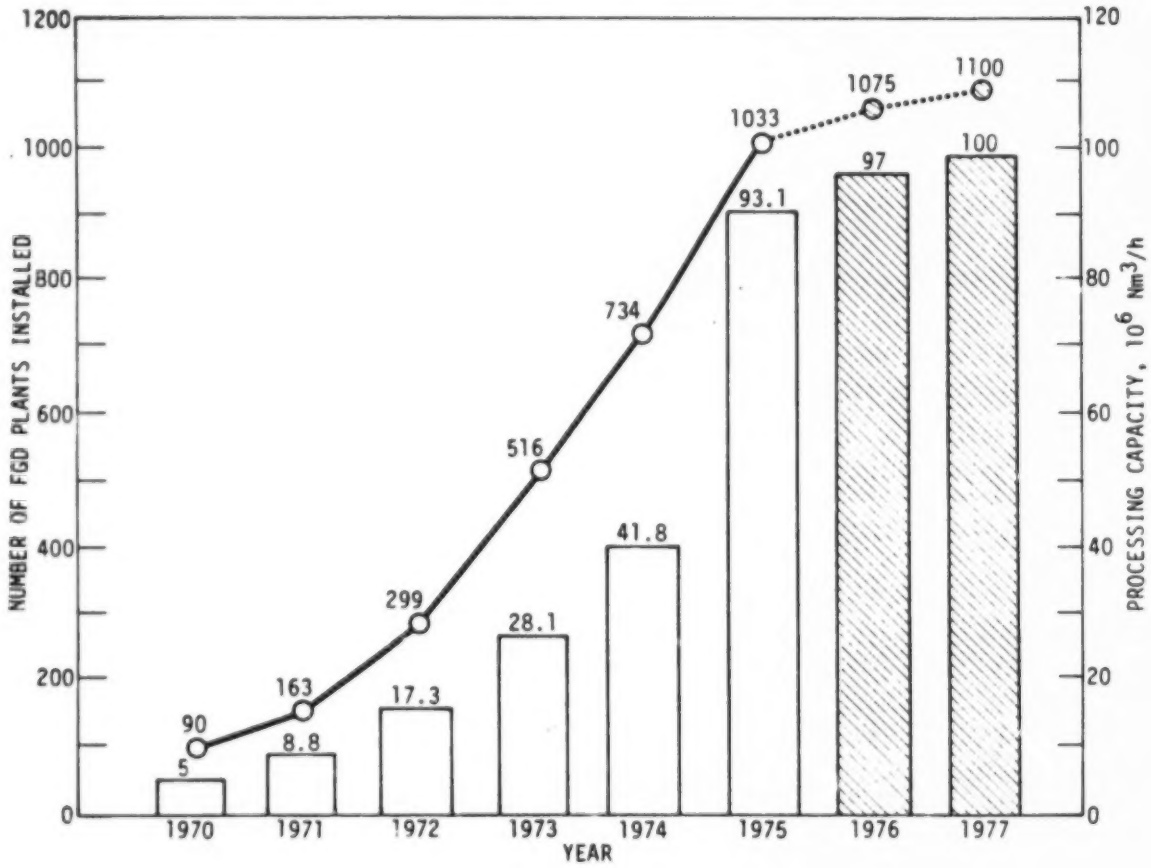

Fig. 3. FGD growth rate in Japan, 1970 through 1977. (Shaded areas represent estimates)

Source: Ref. 11.